Service Date: June 22, 1987

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER of the Application	)	
of MONTANA-DAKOTA UTILITIES for	)	UTILITY DIVISION
Authority to Establish Increased	)	DOCKET NO. 86.5.28
Rates for Electric Service.	)	ORDER NO. 5219c

ORDER ON RECONSIDERATION

GENERAL

1. On March 19, 1987, the Commission approved Order No. 5219b, which disposed of all matters then pending in Docket No. 86.5.28. On April 2, 1987, the Commission issued an Errata Sheet to Order No. 5219b correcting minor typographical errors.

2. On April 13, 1987, the Commission received Motions for Reconsideration from both the Montana-Dakota Utilities Company (MDU or Company) and the Montana Consumer Counsel (MCC). Both parties requested reconsideration on several revenue requirement and rate design issues.

3. Both parties' motions referred to several Finding of Fact Numbers from Order No. 5219b. Many of these references were incorrect because they did not reflect the Errata Sheet discussed above. This Order uses the corrected Finding of Fact Numbers as described in the Errata Sheet.

REVENUE REQUIREMENTS

Acquisition Adjustment

4. MDU voted for reconsideration of Order No. 5219b, Findings of Fact (FOF) 58-77 in which the Commission rate based at original cost the increments of the Coyote and Big Stone generating stations purchased by MDU during 1985 and 1986. The Commission allowed the difference between the purchase price and original cost to be amortized over the remaining lives of the two generating stations.

5. The Commission stated its application of the original cost statute, Section 69-3-109, MCA, and its treatment of resulting acquisition adjustments in Order No. 5020b and reiterated its position in paragraph 59 of Order No. 5219b. MDU has presented no facts or arguments to refute the Commission's consistent application of Section 69-3-109.

6. MDU maintains that the proper treatment of the generating station increments it purchased is to rate base them at the purchase price. The Company argues that the Commission's interpretation of 69-3-109, MCA, has been rejected in State District Court, that the order would discourage the purchase of existing plant, and that it penalizes the Company for selecting least cost planning.

7. The Commission finds no merit in these arguments. The facts in the District Court case, MPC V Dept. of Public Service Regulation, Silver Bow County, Cause No. 63493, 1979 are distinguishable from the purchase of Big Stone and Coyote. That case is not controlling in this Docket.

8. The Commission does not agree that acquisition adjustments will "totally discourage the purchase of existing facilities." (MDU brief p. 2.) Acquisition adjustments should motivate a utility to bargain harder and consider more options when acquiring additional resources.

9. The Commission also rejects MDU's argument that the Coyote purchase reflected least cost planning. An August, 1984 study was the basis for the Company's claim that purchasing 21 megawatts of Coyote in three installments was cheaper for its ratepayers than purchasing the entire 21 megawatts at once. In Order No. 5219b, the Commission discussed the inadequacies of the Company's August, 1984 expansion study (FOF 67-69).

10. The Company states that at the time of the study a final purchase price had not been negotiated, but when the final purchase price was decided upon it was less than the price used in the study. This argument has no bearing on the fact that the Company's decision was based on false assumptions.

11. Quoting from that August, 1984 study:

> MP estimated their accumulative depreciation rate to be 1/35 per unit or 2.86 percent annually. The latest Handy-Whitman Index was 2.36 percent annually on January 1, 1984. Therefore, the capital

> investment cost was assumed to decrease by 0.5 percent annually after 1985. (emphasis added)

Comparing the prices paid for the first two Coyote increments shows that the capital investment cost increased by over $264,000 during the eight month period between the two purchases. The study assumed a decreasing investment cost per unit while the actual investment level per unit increases each year. During the same eight month period the Coyote plant continued to be operated as a base load plant, thereby decreasing its remaining useful life because of the actual wear and tear of normal operations.

12. On reconsideration MDU asserts that the entire investment would have been immediately reflected in rate base if Coyote had been purchased at book value, the Commission addressed this argument in FOF 62 by quoting MCC's expert's testimony:

> It is my opinion that MDU was concerned about an excess capacity disallowance if all 21 MW of Coyote was purchased at one time and, rather than risk such an event, the Company was willing to pay a premium for the ability to better match the acquisition against the existing load forecasts. The problem now is that while the Company does not appear to be long on capacity, the ratepayers are being asked to pay higher return and depreciation dollars because of the "escalated" price paid for the first two increments of the Coyote purchase (MCC Exh. 5, p. 11).

13. On reconsideration, MDU also argues that FOF 77 implies that the investors are receiving a return on the portion of their investment in the generating station which have been recorded as acquisition adjustments. FOF 77 is not meant to imply that shareholders are receiving a rate of return on that portion of the investment. To clarify any ambiguity, on reconsideration, FOF 77 is redrafted to state:

> 77. Mr. Clark's proposal allows for the investment to be recouped by the stockholders over the useful lives of the Coyote and Big Stone plants and also protects the ratepayer from paying a rate of return on a rate base that is recorded above original cost. The Commission finds this approach to be fair, and therefore, accepts Mr. Clark's proposal resulting in a rate base reduction of $812,447, and a $71,774 increase in expense reflecting the annual amortization of the acquisition adjustments.

14. MDU's motion that the Commission include Big Stone and Coyote in rate base at a value in excess of the original cost of the property is DENIED.

Captive Coal

15. The Commission received Motions for Reconsideration from both MDU and MCC on this issue. MCC's Motion pertains to the Commission's use of year-end equity for Knife River Coal Company and will be addressed prior to MDU's Motion.

16. MCC objected to the Commission's use of year-end equity to calculate Knife River's actual rate of return. The Consumer Counsel believes that using average equity does not constitute a ratemaking adjustment being applied Knife River, a non-regulated affiliate. MCC stated that average equity provides a better match of earnings and the equity invested to generate those earnings.

17. MCC correctly interpreted the Commissions rationale for using year-end equity in Docket No. 83.9.68. In that case the Commission found that using year-end equity provided consistency in comparing the rate of return for Knife River with the rates of return earned by the comparable companies whose returns were based on year-end equity. To not maintain that consistency would have caused an overstated adjustment to MDU's allowable coal expense.

18. However, after reviewing the record in this proceeding the Commission finds that it did not apply the rationale correctly in this Docket. The comparable coal companies' rates of return as supplied by MCC witness, Mr. Basil Copeland, were actually calculated on an average equity basis. The return on equity for Baukol-Noonan that was supplied by MDU witness, Mr. Wallace Wilson, was also calculated on an average equity basis. These average equity figures were relied on to determine the appropriate return for Knife River coal sales to MDU and therefore, it provides a better match to use Knife River's average equity in the adjustment.

19. Pursuant to the above discussion, MCC's Motion to use Knife River's average equity in the adjustment is GRANTED. The adjustment is recalculated below:

	(000)
Knife River 1985 Average Equity	61,827
Equity Return at 13%	8,038
Actual Knife River 1985 Net Income	12,057
Excess Knife River Net Income	4,019
Tax Multiplier (1)	x 1.3538
Total Excess Revenue	5,441
MDU % Knife River Sales (2)	x .2976
Excess Revenue on Sales to MDU	1,619
Montana Allocation Factor #2	x .32606
Approved Level of Adjustment	528

20. The affect of using average equity in the adjustment is an additional $79,000 (528,000 - 449,000) decrease to MDU's allowed coal expense.

21. The Company presented several reasons why it thought the Commission's coal adjustment was wrong. Each of these positions are discussed herein.

A. The Adjustment Indirectly Regulates Knife River:

22. MDU argued that indirect regulation of Knife River Mining Company is the real goal of this adjustment. The Company bases its argument on the fact that the profit for Knife River was calculated on a total company basis, not strictly on sales to MDU. The Company further reported that the "coal sales which generate the most money for Knife River are not even utility sales, but industrial sales.

23. The Commission is not attempting to regulate Knife River directly or indirectly; the Commission merely uses Knife River's return on equity as a measurement of the reasonableness of MDU's coal expense. The amount of coal and the price differential for Knife River's industrial customers do not significantly affect Knife River's total return on equity. The only way that the coal company's total return would be inappropriate is if Knife River charged MDU significantly less for

coal than it charges the majority of its other customers. The evidence in the record shows this is not the case (MDU Exh. O, Exh. WWW-5).

B. The Commission's Decision Is Premised On A Number Of Fundamentally Incorrect Findings and Assumptions:

24. The Company asserts that the adjustment to coal expense was never addressed by the parties. Thus MDU was deprived of the opportunity to rebut the adjustment or cross-examine the authors.

25. The adjustment is based on the proposal by MCC with one difference: The Commission included Baukol-Noonan return figures with the evidence presented by MCC in the determination of a fair rate of return on Knife River coal sales to MDU. The Company's own witness, Mr. Wallace Wilson, found Baukol-Noonan to be "uniquely comparable" to Knife River. It does not make sense to this Commission that MDU would object to the use of such a "uniquely comparable company in the determination of a fair rate of return on Knife River coal sales to MDU.

26. In making this adjustment the Commission analyzed all the data and evidence presented in this proceeding to determine the proper level of coal expense. This is consistent with what the Commission does when examining the proper level of other MDU expenses such as labor and fringe benefits. The Company's position, if followed to its logical conclusion, would suggest that the Commission must choose either MCC's or MDU's position on an issue without the discretion to make reasonable adjustments to either parties' positions.

27. MDU's argument that Otter Tail Power negotiated the coal contracts for the Coyote and Big Stone generating stations is irrelevant. The fact that MDU is a participating owner in the two generating stations, which consume Knife River coal, necessitates that the Commission carefully scrutinize these coal costs that are being charged to MDU ratepayers because of the relationship that exists between MDU and Knife River.

C. <u>The Adjustment Is Unreasonable:</u>

28. The Company argues that the adjustment is unreasonable because the return on coal sales to MDU that was determined to be reasonable for Knife River in this Docket is not the same as the 14.565% determined in Docket No. 83.9.68. The Commission finds no merit in this argument. The financial markets have improved since Docket 83.9.68 and therefore a lower rate of return would be expected. As discussed in Order No. 5219b, the price that MDU pays for coal is based on production costs with a provision beyond that to recover an agreed upon level of profit. When the Commission examined the reasonableness of MDU's reported coal costs using a rate of return analysis, it relied on the same standard used by Knife River to establish the price it charges for coal: cost plus profit.

29. As discussed above, the Commission included Baukol-Noonan return figures in the determination of a fair rate of return on Knife River coal sales to MDU. The 1984 (13.8 percent) and 1985 (11.0 percent) return figures for the Mining, Crude Oil Production Group, as presented by MCC (MCC Exh. 4, Exh. BLC-2, Sch. 8), are the medians of the group. When Baukol-Noonan was combined with this group the returns were incorrectly interpreted as averages. Therefore, Finding of Fact No 168 lists the 14.2 percent 1984 return figure and the 11.8 percent 1985 return figure which is incorrect and should be deleted from the Order. By so doing, the Commission does not find this change to affect its 13 percent rate of return determination because the remaining evidence still suggests that this return is appropriate.

<u>Retired Plants</u>

30. MCC argued that the Commission was incorrect in not removing the assumed contingency from the Williston and Bismarck plants. The Consumer Counsel stated that the Company did not challenge that assumption. MCC also believes that because a contingency factor was included in the Stone & Webster studies it is logical to assume that MDU included them in its decommissioning estimates for the Williston and Bismarck plants.

31. The Commission believes that its treatment of contingency factors was consistent. Where a contingency factor was listed in an estimate, it was removed. In Order 5219b the

Commission stated that this issue will be reviewed again in the next MDU electric rate proceeding. If it is found that the Company has over-collected on the retirement of these plants, then an adjustment will be made to compensate ratepayers for the over-collection. MCC's Motion is DENIED.

Depreciation Rates

32. MCC requested that the Commission reconsider its decision on depreciation rates for the Big Stone, Coyote, Heskett and Lewis & Clark generating stations. The Consumer Counsel reported that the North Dakota and South Dakota Utility Commissions did not allow MDU to change its depreciation rates for these generating stations. MCC further stated that "different depreciation rates in the different jurisdictions will create additional burdens" for all parties in future rate cases. The Consumer Counsel believes that this may cause an incorrect allocation of various depreciation related items among the jurisdictions in which MDU operates.

33. This Commission does not expect uniform treatment of all issues by all regulatory bodies. The evidence in this Docket persuaded this Commission that the established depreciation rates are reasonable.

34. MCC also suggests that when one regulatory body arrives at a different decision, then incorrect allocations among the various jurisdictions will result. This argument is also rejected. The Commission reiterates that different decisions have previously been reached by the various regulatory bodies and, in all likelihood, will be in the future. If MCC's argument were true, then the allocations would already be incorrect. No evidence of this charge was presented in this proceeding. Therefore, this Motion is DENIED.

AVS II

35. MCC has moved for the reconsideration of FOF 143 and 144 that state:

> 143. Additionally, the Commission found a severe deficiency in Mr. Clark's proposal. That deficiency pertains to his treatment of Sch. E purchases. The MAPP agreement that is on file with this Commission specifically defines economy energy as:

> ...energy which one Participant may deliver under Service Schedule "E" to another Participant for the purpose of replacing more expensive energy.
>
> 144. This means that the Company must reduce its generation of energy by an amount equal to the energy purchased under MAPP Sch. E. Mr. Clark's proposal treats Sch. E energy as an additional long term energy source for MDU, when in reality it is no more than a cost reducing mechanism which cannot be acquired without first having other energy sources that can be forgone. The Commission finds that MCC's proposal is simply not feasible. The Company's proposal to include the costs associated with the AVS II firm power purchase is accepted resulting in a $1,518,412 increase to the per books fuel and purchased power expenses.

36. MCC asserts that the Commission incorrectly found a "severe deficiency in Mr. Clark's (MCC's expert witness) testimony." On reconsideration the Commission agrees with MCC and withdraws FOF 143 and 144.

37. The Commission's finding that there was a deficiency in the testimony was based on an incorrect interpretation of information in MCC Exhibits 5 and 6. In Order 5219b the Commission's review of MCC's proposed power supply mix assumed that the proposal was premised on treating MAPP Schedule E energy as a long term energy source. Since Schedule E is not a long term energy source, the Commission rejected MCC's proposal. In it brief on reconsideration, MCC showed that the Commission misconstrued MCC Exhibits 5 and 6 and MCC's treatment of Schedule E. MCC's proposal does not treat Schedule E as an additional long term energy supply; the proposal treats Schedule E as a source of economic energy to be purchased to displace higher cost energy sources already owned by MDU. This is, in fact, what Schedule E is to be used for and makes MCC's proposal feasible.

38. To establish this point in its brief on reconsideration, MCC refers to the Company's response to MCC's Initial Data Requests No. 13 to the Kroeber testimony. The response is the Company=s backup for its fuel and purchased power adjustment. The response is broken into various steps called Case I, Case II, Case III. Each Case shows the incremental affects of the Company's 1985 and 1986 resource acquisitions in terms of megawatt hours (mwh) and fuel or purchased power

dollars. Case II models plant generation levels, fuel costs and power purchases as if the March, 1985 Big Stone plant, September, 1985 Coyote plant and the May, 1986 Coyote plant purchases were available for the Company to utilize all year. The AVS II resource was not included in Case II. Under this scenario, the Company listed 139,288 mwh of nonfirm Schedule E energy purchases. MCC contends that this information suggests that the Company could have foregone at least 139,288 mwh of generation from its own units to acquire the Schedule E energy. Case II and Case III are shown below:

	Case III MWH	Case II MWH	Impact MWH	Impact Dollars
Generation:				
Heskett	444,336	449,683	(5,347)	$ (92,888)
Lewis & Clark	171,972	183,167	(11,195)	(121,060)
big Stone	503,362	535,499	(32,137)	(434,720)
Coyote	509,846	549,917	(40,071)	(395,254)
Miles City	141	141	-0-	-0-
Glendive	157	157	-0-	-0-
Subtotal	1,629,814	1,718,564	(88,750)	(1,043,922)
Purchases				
Non-Firm	74,650	139,288	(64,638)	(901,700)
Firm	198,560	-0-	198,560	9,697,195
Subtotal	273,210	139,288	133,922	8,795,495
Interchange	27,499	27,499	-0-	-0-
Subtotal	1,930,523	1,885,351	45,172	7,751,573
Other Sales	(109,310)	(64,138)	(45,172)	(749,404)
Totals	1,821,213	1,821,213	-0-	7,002,169

39. MCC's proposal reflects less Schedule E energy than the Company's Case II. This means the amount of Schedule E included in MCC's proposal is within the limits of what the Company believed it could have acquired. The Schedule E energy from MCC's proposal actually replaces energy that the Company could generate from its own plants and does not replace AVS II energy. Therefore, the Commission agrees that MCC's proposal does not treat Schedule E energy as

an additional long term energy source. FOF 143 and 144 are based on incorrect assumptions and should be removed from Order No. 5219b.

40. In its motion on reconsideration, MCC reiterates that its expert's cost comparisons between existing generation and AVS II purchased power are correct. MCC maintains that when AVS II was added to the resource mix it displaced existing resources and increased off system sales. It is MCC's position that it is inappropriate to increase costs to the ratepayers by over $7 million while providing no net change in system resources.

41. Because the Commission misinterpreted Clark's treatment of Schedule E purchases, it viewed that AVS II energy as displacing only 88,750 mwh of Company generated energy. The table on page 12 shows that the AVS II purchase:

1) Displaces current energy production - 88,750 mwh.
2) Displaces Schedule E energy that the Company could have produced with its own units - 64,638 mwh.
3) Increases off system sales - 45,172 mwh.

42. Because the Schedule E purchases could have been generated from the Company's own plants, the amount of displacement was actually 153,388 mwh (88,750 + 64,638). This represents over 77 percent of AVS II energy being used to displace energy that MDU could have generated internally, with an additional 45,172 mwh of AVS II energy being surplus to the extent that it is sold off system. Even though the Company did not acquire the AVS II resource to displace existing energy sources, that is, in fact, what happened when AVS II was added to MDU's resource mix. Therefore, the Commission agrees that Mr. Clark's cost comparisons between existing generation and AVS IT purchased power are correct.

43. MCC presented evidence showing that the AVS II power purchase is more expensive for ratepayers than buying capacity from MAPP and generating energy with the Company's existing power plants. The MCC' proposal provides the Company with its test year energy requirements plus enough capacity to meet future demand. It strikes a compromise by repricing the AVS II purchase:

> This recommendation could be viewed as a compromise since it could be argued that, at the present time, it is patently obvious that the purchase of AVS II power is more expensive than any reasonably alternative available to MDU, including Schedule B purchase from

> the' MAPP pool. Although conservative, I believe my recommendation does recognize that the Company needs to have some flexibility to make long-term plans and, at the same time, protects Montana ratepayers from some of the costs of a very expensive power source. (MCC Exh. 5, pp. 35-36)

44. The Commission finds that MCC's proposal is feasible and it would allow the Company to meet its obligation to serve. MCC's Motion to reprice AVS II is GRANTED.

45. The impact of the Commission's reconsideration of this issue is a $1,474,932 decrease in fuel and purchased power expenses approved in Order 5219b. The magnitude of this change merits a brief review of the issue. MDU's substantial revamping of its power supply mix since the spring of 1985 made the appropriate level of fuel and purchased power expense a significant issue in this Docket. MDU asked the Commission to approve the following power supply mix.

1.	March 1985 - purchase additional Big Stone	+ 12 MW
2.	Sept. 1985 - purchase additional Coyote	+ 5 MW
3.	Nov. 1985 - retire Williston steam	- 2 MW
4.	Nov. 1985 - retire Glendive steam	- 7 MW
	1985 Net change	+ 8 MW
5.	May 1986 - purchase additional Coyote	+ 5 MW
6.	June 1986 - purchase power from AVS II	+ 41 MW
7.	May 1986 - retire Beulah plant	- 14.5 MW
8.	May 1986 - retire Mobridge diesel	- 2.6 MW
9.	May 1986 - retire Ellendale diesel	- 2.8 MW
	1986 Net change	+26.1 MW
	Total Change	+34.1 MW

46. In Order 5219b, the Commission accepted the retirement of Williston, Glendive, Beulah, Mobridge and Ellendale. Subject to the acquisition adjustment, it also accepted the additions to rate base of the increments of Big Stone and Coyote which MDU purchased. AVS II was the remaining issue in the power mix. MDU chose to enter a firm power purchase contract for the AVS II energy and agreed to purchase approximately 41 MW of AVS II power (9.2%).

47. MAPP Schedule E and Schedule H power are relevant to the Commission's resolution of the AVS II issue. MDU is a member of the Mid-continent Area Power Pool (MAPP). MAPP is a organization of 46 power producers that, among other things, form an integrated system for purchase and sale of surplus power. All members of MAPP must maintain an individual reserve requirement of 15 percent. (MDU Exhibit P, pp. 8-10) Schedule E is non-firm energy -- a seller may cancel the sale with a one day notice. Schedule E is available to displace more expensive energy, but a buyer must have energy sources to forego in order to purchase Schedule E. Schedule H is a firm energy and power source limited to a load factor of 20 percent. MCC introduced evidence (MCC Exh. 5, AEC-4) projecting a surplus in MAPP until at least 1995. As noted in FOF 37 of Order 5219b, MCC's expert testified that there is an abundance of Schedule H power and energy and Schedule E energy for MDU to purchase (MCC Exh. 5, p. 35).

48. In its original analysis of MCC's proposal, the Commission incorrectly assumed that MDU did not have energy sources to forego; MCC has clarified that MDU could, in fact, back down resources. In adopting MCC's proposal on AVS II, the Commission considered MDU's load from both a peak and energy basis.

49. MCC proposed to reprice AVS II purchase as if:

1) MDU's coal fired generation is increased to its pre AVS II level,

2) The increased off-system sales are eliminated.

3) A MAPP Schedule H purchase is assumed to be the needed capacity with associated energy for the number of hours that the Miles City turbine operated in 1985.

4) The remaining energy is purchased at the latest estimate of MAPP Schedule E available at the time of the hearing. (MCC Exh. 5, p. 34).

50. On reconsideration, with the clarification concerning Schedule E, the Commission agrees with MCC that this represents options that were available to MDU and will be available into the future.

Final Revenue Requirement

51. The following table shows that the Company must reduce its revenues by $1,557,905 so that it will not be in an excess earning situation. The net revenue increase for Docket No. 86.5.28 is $235,859, resulting in total annual revenues for MDU of $32,156,803.

	Order 5219b Totals (Includes TRA)	Approved Changes	Revised Totals	Increase (Decrease) for 10.655% Return	Total	Pro Forma Revenues Order 5219b	Net Revenue Change Dkt 86.5.28
Operating Revenues	33,714,707		33,714,707	(1,557,905)	32,156,803	31,920,944	235,856
Expenses:							
Fuel & Purch. Power	9,800,056	(1,533,932)	8,246,124		8,246,124		
Operating & Maint.	8,188,871		8,188,871		8,188,871		
Total	17,988,927		16,434.995		16,434,955		
Depreciation	3,927,706		3,927,706		3,927,706		
Taxes - Non Income	1,502,949		1,502,949		1,498,976		
Fed and State Tax	2,159,749	684,507	2,844,256	(3,973)	2,159,749		
Deferred Income Tax	983,873		983,873	(684,507)	983,873		
I.T.C.							
Amort of I.T.C.							
Total Operating Exp	26,563,204	(869,425)	25,693,779	(688,480)	25,005,299		
Amort Pre-1974 Gain	14,000		14,000		14,000		
Operating Income	7,165,503		8,034,928		7,165,503		
Rate Base	67,250,149		67,250,149		67,250,149		
Rate of Return	10.655%		11.948%		10.655%		

COST OF SERVICE AND RATE DESIGN

52. The organization of this section of the order is to first respond to the motions for reconsideration. This first section is followed by Commission decisions on rate design which are required to reflect the lowered revenue requirement.

53. Background: The Commission's Interim Order No. 5219a in this docket provided for a $884,507 annual revenue increase which was recovered on a uniform percent increase basis from all but Rates 16 and 23. The Commission's final Order No. 5219b allowed an increase in annual revenues of $2,290,229 less the impacts of the 1986 Tax Reform Act for a final increase of about 1.8 million dollars.

54. Commission decisions on motions for reconsideration in this docket have subsequently lowered the increase in the Company's total revenue requirement. As a result, the Commission's cost of service and rate design decisions in its final Order No. 5219b would, of necessity, have to be revisited. The impact of the lowered increase in the Company's revenue requirement, and the Commission's decisions, will follow the below review of motions for reconsideration on cost of service and rate design.

MOTIONS ON

COST OF SERVICE AND RATE DESIGN

55. Introduction and Summary: In this introduction and summary the Commission will briefly outline the nature of the motions received on cost of service and rate design and its decisions. For a more detailed description of the issues and Commission decisions a reading of the balance of this order is advised.

56. Motions for reconsideration on cost-of-service and/or rate design (COS/RD) were received from both MDU and MCC. MCC raised motions on COS and RD. MDU's motions were limited to RD, but with cost of service implications. To summarize, MCC's COS motions address the Commission's decisions on distribution demand costs, customer costs, reconciliation and marginal energy (running) costs. MCC's RD motion involved the Commission's decisions on the Residential class' RD. MDU's RD motions involve the Dual Fuel and Optional time-of-day tariff.

57. In summary of the decisions on cost of service motions, the Commission would note the following. First, the Commission granted the MCC motion to rely on the initial and not updated forecasts by the Company of marginal running costs. Second, the Commission denied the motion to use the MCC's reconciliation approach in lieu of an "equal percent" approach. Third, the Commission denied the MCC's motion to adopt its proposed basis for computing distribution and customer costs. While not based on a motion, the Commission also required the Company to correct an error in its March 19, 1987, compliance filing having to do with the levelization of marginal running costs.

58. To summarize its decisions on rate design motions, the Commission would note the following. First, because of concerns with the cost basis for MDU's proposed Dual Fuel tariffs, the Commission approved MDU's request to revise the rates per its motion. The Commission, however, also finds that the dual fuel rates must be "frozen" (grandfathered). Second, the Commission denied MDU's request to withdraw its optional time-of-day tariffs, preferring to freeze the offerings at this time. Lastly, the Commission granted the MCC's motion to lower the residential Base Rate to a level of $3.00.

COST-OF-SERVICE MOTIONS

59. Overview: MCC's motion requests the Commission to reconsider several COS decisions including: 1) "the decision to adopt the Montana-Dakota Utilities Company ("MDU") approach to compute distribution and customer costs ultimately used in developing class revenue requirements.", 2) "the use of a revenue reconciliation technique that treats all functional components of cost of service as equal candidates for such reconciliation", and 3) the "decision to use updated marginal energy costs based on radically different underlying assumptions than were testified to by MDU and which significantly affect the development of class revenue requirements." Each of these motions are reviewed in turn.

60. Distribution Costs: In the following findings the Commission will first review MDU's and the MCC's proposed bases for distribution costs. This review is followed by a review of the MCC's motion and then the Commission's decision.

61. The Commission's Order No. 5219b described MDU's and MCC's calculations of distribution costs which is repeated here. MDU's distribution costs are made up of capital and expense components ($/kw). The demand component is a net calculation. For historic and forecast costs (1976-1990), MDU regresses (using econometrics) the net cost of distribution system additions on peak demand. The sense in which the costs are "net" is that MDU first reduces the distribution investment by an estimate of the customer-related costs using seven years of average cost data in constant 1986 dollars. MDU's estimate of distribution expenses derives from a classification of total expenses by demand and customer. The classification stems from MDU's Fully Allocated Embedded Cost of Service study. Demand-related expenses for each year are divided by the annual Montana distribution peak for each year and averaged.

62. The MCC's development of distribution costs derives from the MCC's Other Functional Costs category which are the non-Bulk power supply costs. MCC's estimates of non-BPSCs derived from MDU's embedded COS study. MCC argued that the reasons for basing generation type costs on marginal cost analyses do not hold for the development of distribution costs. MCC modified MDU's embedded costs for use in its COS study. MCC's modifications involved the classification of distribution plant investment in poles, towers, fixtures, conductors, conduits and line transformers in FERC accounts 364-368. Unlike MDU, MCC classifies 100 percent of the costs in these accounts to demand (MDU classified 35 to 72 percent to demand depending on the account and the remaining percent to customer related).

63. The MCC moved the Commission to reconsider its decision to adopt the Company's methodology for computing marginal distribution costs, and assumably adopt the MCC's approach.

64. The Commission's decision on how distribution costs should be reflected in the COS study was to maintain the status quo. Due to concerns the Commission had with each parties' proposals, the Commission opted to retain the same method adopted in the last MDU electric docket (Docket No. 83.9.68, Order No. 5036a). In the previous docket, the MCC did not file a motion for reconsideration on this decision. The Commission finds no reason to deviate from the status quo pending the submittal of a more accurate marginal cost estimate than filed by MDU.

65. Several additional comments in this regard are noteworthy. First, in further defense of maintaining the status quo with regard to how distribution costs should be computed, the Commission's below response to MCC's "Other Issues" is relevant. Second, as an analogy to maintaining the status quo, the Commission would note that while it shares the same concern MDU expressed with MCC's development of marginal transmission costs, the Commission preferred and adopted MCC's approach (see Finding of Fact No. 274 of Order No. 5219b).

66. A final comment regards MCC's reference to MDU's "Exhibit Nos. 7 and 9" dated March 23, 1987 (see MCC Motion, p. 3). MCC's reference seems to suggest the information is new in this docket. It is not. The Commission would note that these exhibits are precisely Mr. John Castleberry's direct testimony (Exhibit No, JKC-12, page 1, and JKC-14, pages 1 and 2), adjusted to 1988 dollars. That is, the cost evidence is not new. What appears new is MCC's specific concerns with MDU's analysis.

67. <u>Customer Costs:</u> The following reviews, in turn, the Company's basis for customer costs, the MCC's motion and the Commission's reasoning for rejecting the MCC's motion. The Commission's order also described how MDU and the MCC computed customer costs. MDU's customer-related costs derived from a "minimum investment per customer" philosophy which in turn reflected the cost required to connect a new customer in Montana and in 1985.

68. The MCC's motion states "{T}he use by the Commission in Finding of Fact No. 278 of MDU's marginal customer cost computation explicitly accepts the proposition that the proper basis for measuring customer costs is to assume that all customers are newly connected to the system." MCC requests the Commission to reconsider its decision to utilize the Company's methodology in computing marginal customer costs.

69. The Commission's decision in Order No. 5219b described how customer costs should be developed and used for COS purposes and emphasized the "problematic" nature of the calculation. It is also important to note that the Commission did not adopt "MDU's marginal customer cost computation" in its entirety as MCC's motion suggests (Order No 5219b, Finding of Fact No. 278 and 279). The Commission's decision only adopted part of MDU's proposal as reiterated below.

70. The Commission's decision on how customer costs should be computed for COS purposes attempts to reflect relevant marginal costs. As a starting point in the process, the Commission looked at MDU's marginal customer cost estimates. Next, the Commission excluded certain costs that the Commission believed were not marginal. A remaining cost included, for example, meter costs. In retaining these costs in the marginal customer cost calculations, the Commission recognized that there is an opportunity cost to certain plant investment given that the plant is fungible (TR 73). If the use of opportunity costs is now in error, which the Commission believes it is not, then nearly every recent electric order dealing with COS and avoided costs is flawed. If opportunity costs are now irrelevant in COS studies, the Commission will have to take a different tack in all future electric dockets (e.g., COS values of power in retail rate and avoided cost dockets).

71. Another comment is also noteworthy regarding past opportunities interested parties have had to influence MDU line extension policies and to an extent customer cost calculations. The Commission's final Order No. 5219b in the present docket, stated a preferred approach for recovering certain marginal customer costs that is via a line extension policy. Subsequent to issuing Order No. 5036a in MDU electric Docket No. 83.9.68, MDU filed to revise its gas and electric line-extension policy (in 1985). The Commission noticed the filing for public hearing and assigned Docket No. 85.2.9. No protests and or requests were forthcoming from any party on MDU's proposal (see Default Order No. 5131, March 27, 1985).

72. <u>Other Issues:</u> While not clearly a motion for reconsideration, MCC included a comment in its motion under the subtitle "Other Issues". As noted above, this section appears to relate to MDU's motion on distribution costs which was reviewed earlier. The MCC comment responds to the Commission's findings in Order No. 5219b that there is an inconsistency in the parties proposals on how certain distribution plant should be classified. The following findings review, in turn, MCC's comments and the Commission's response.

73. In this section of its motion, MCC stated, in part, "... the Commission takes exception with the perceived differences in the MCC's classification of certain distribution costs in the electric

area in comparison with the gas area. n (Motion, page 7) This comment by MCC largely appears to relate to the Commission's distribution cost choice in Order No. 5219b of the current docket.

74. To summarize, the Commission is unmoved in its original criticism, and further buttresses its argument that there exists an inconsistency in how the MCC proposes to classify distribution plant. The Commission's additional argument stems, in part, from MCC's own testimony in the most recent gas docket relative to the present electric docket. First, in the gas docket MCC's argument for classifying gas mains between energy and demand is as follows:

> In contrast to MDU, Mr. Drzemiecki holds gas utilities design their local distribution systems based on expected load patterns: that is, the distribution mains must satisfy the non-coincident maximum customer demands as well as the average energy requirements (Finding No. 128, Order No. 5160a, Docket No. 85.7.30) (emphasis added).

75. Then, in the current electric docket MCC states:

> The decision to construct particular types and quantities of distribution plant to service local needs is predicated upon the expected load patterns that the localized network is likely to experience...{A}s a result, there must be sufficient capability to satisfy the non-coincident maximum demands of these customers (Mr. Drzemiecki's direct testimony, page 50j (emphasis added).

76. To summarize the above two quotes, MCC's testimony has been that the design and/or construction of gas and electric distribution systems has been equally based on expected load patterns and the systems must equally satisfy the "non-coincident maximum" customer demands. In its motion, MCC now states, that gas mains serve primarily a transmission type function. Yet, MCC proposes the same non-coincident peak allocator for gas distribution costs as for electric distribution costs. Transmission plant, however, is typically allocated on a system coincident peak basis.

77. With regard to how gas distribution plant should be allocated in the gas docket, MCC made the following analogy between gas and electric distribution systems (in the gas docket):

> ...theoretically, the peak-day requirement should be a non-coincident peak. It's perfectly analogous to the situation that one faces when one is trying to determine the proper allocation technique for electric

> distribution plant, for example. (Finding of Fact No. 135, Order No.5160a) (emphasis added).

78. Therefore, the Commission's initial position, as stated in Order No. 5219b, remains unchanged.

79. As a final comment, the Commission finds that if a proper analysis were performed, one could end up classifying distribution plant to one or more of three categories: 1) demend, 2) energy and/or 3) customer. As there is no convincing argument raised in MCC's motion on this issue, the Commission chooses to not rescind its original decision.

80. Revenue Reconciliation: The MCC's motion with regard to reconciliation featured a request for the Commission to rescind its "equal percent reconciliation" approach. The MCC's motion also contained other statements of import and concern to the Commission. The following reviews why the Commission denies MCC's motion, and also responds to these other statements by the MCC.

81. The Commission's order summarized MDU's and MCC's detailed and technically complex reconciliation proposals which will not be repeated here. In responding to MCC's motion, the Commission will explain why it chooses not to deviate from an "equal-percent" approach, followed by a response to the specific statements raised by MCC.

82. Historically speaking, the Commission's policy on reconciliation has been uniform in all recent electric dockets. In the last MDU electric docket (Docket No. 83.8.68), the Commission required an equal-percent reconciliation. In the most recent Montana Power Company and Pacific Power and Light electric dockets (respectively Docket Nos. 83.9.67 and 85.10.41) an equal-percent reconciliation was also required.

83. The reasons the Commission adopted an equal-percent reconciliation in MPC Docket No. 83.9.67 are most interesting. First, in this MPC docket Mr. Drzemiecki's colleague Dr. John Wilson, on behalf of the MCC, identified "...two approaches which may be used to adjust marginal costs to MPC's embedded costs or revenue requirement level" (Direct Testimony of Dr. John Wilson, Docket No. 83.9.67, page 76). One approach that Dr. Wilson says "may" be used "...reconciles marginal costs to the revenue requirement by adjusting all functional cost categories." emphasis

added (ibid) Now in the current MDU electric docket Dr. Wilson's colleague, Mr. Drzemiecki, holds that this one approach is apparently flawed.

84. Second, in the MPC Docket No. 83.9.67, the Commission also stated the following in support of adopting Dr. Thomas Power's equal-percent reconciliation:

> The Commission finds that the most equitable reconciliation of class marginal cost revenue requirements is Power's equi-proportional adjustment. This is the same approach proposed by <u>Company</u> witnesses in other electric rate cases. (MDU Docket No. 83.9.68, and PP&L Docket No. 83.5.36.) (See Order No. 5051d, Finding of Fact No. 169.)

85. The following findings respond to certain other statemeets made by the MCC on the issue of reconciliation. Organization of the Commission's responses follow the order in which the MCC raised the issues in its motion. The issues reviewed below include: 1) MCC's 280 percent figure, 2) MCC's connection between revenue requirements and cost of service and 3) MCC's allegation that the Commission's "equal percent" approach results in the Company earning excess revenues and encourages the abuse of monopoly power.

86. The Commission's first response is to the second paragraph under the topic Revenue Reconciliation that begins on page 8 and ends on the top of page 9 of MCC's motion. The Commission finds the 280 percent figure an exaggeration for the following reasons. The first reason stems from MCC's exclusion of the PSC's final revenue requirement and exclusion of the Base-Peak energy portion of the MAPP Schedule B purchases. If MCC included these separate impacts, this precent would fall.

87. Moreover, the MCC's 280 percent value is conceptually erred regardless of the above impacts. The MCC's error is one of confusing "times" with "percent": Under one revenue requirement scenario embedded bulk power supply costs exceed marginal bulk power supply costs, but by 2.8 "times", or equivalently only 180 "percent", <u>not</u> 280 percent. The MCC's reference to 280 percent overstates the impact of one revenue requirement scenario by 55 percent. The Commission previously attempted to correct the record in this regard (Order No. 5219b).

88. Second, there also is need to respond to MCC's parenthetical "See Arg. II infra" in this paragraph on the top of page 9 of the motion. In this comment, the MCC has attempted to weave

together the Commission's Revenue Requirement (RR) and Cost of Service (COS) decisions with the conclusion that there is an inconsistency between the two. In any of the above referenced dockets (i.e., MPC, PP&L and MDU), there has been limited overlap and consistency between RR and COS: The objectives, of 1) setting a revenue requirement and 2) recovering the same revenue requirement based on cost of service and rate design, are dissimilar. The RR and COS objectives cross paths only in the constraint imposed on final prices: Final prices may only generate the total accounting revenue requirement. As succinctly stated by the MCC's COS/RD witness in the current docket, the objective of COS and pricing is efficient resource allocation (see Exh. MCC-2, p. 12 and 19).

89. In turn, efficient prices should reflect future avoidable costs. In this docket, the Commission has approved of both MDU's and MCC's proposals to look to beyond year 2000 for certain relevant avoidable costs for both COS and pricing. Yet, no MCC witness proposed the use of the same avoidable costs in arriving at MDU's revenne requirement. This docket looked at an historic test year to arrive at a revenue requirement (year 1985). The prices out of this docket on the other hand, and based on the Commission's order, will reflect 1988 dollar costs. MCC agrees with this objective. What was done in this docket is similar to what has been done in other dockets in terms of using accountinq costs for revenue requirement purposes and marginal or avoidable costs for COS and pricing purposes.

90. As a final comment on this paragraph, it is interesting to note the MCC did not object to, and file a motion for reconsideration on, the Commission's use of the Base-Peak approach applied to MAPP Schedule B and H purchases to compute a second relevant generation-related avoidable energy cost. In turn, this calculation stemmed from MDU's forecast purchases of MAPP Schedule B in the summer months beginning in year 1987 (2 MWs) and continuing beyond year 2000.

91. The MCC's third and final paragraph on reconciliation (Motion, page 10) is of great concern to the Commission. This issue raises generic concerns involving elasticity-based revenue adjustments to prevent the earning of excess profits and monopoly power abuse. The following will review the source of, and then respond to, the MCC's concern.

92. The MCC's paragraph refers to a finding of fact in Order No. 5219b, which reads as follows:

> The equal-percent approach, when applied to total class revenue requirements, is relatively blind to market impacts. After the uniform percent increase is applied at the class level, recognition of relative margin al costs for the various intra-class products may mitigate adverse market impacts i.e., a non-uniform percent increase or inverse-elasticity pricing may be used on an intra-class basis.

The MCC holds this entire finding of fact "is totally erroneous" and that an equal-percent reconciliation is not blind to market impacts. The MCC paragraph includes other refutable propositions that will be discussed below.

93. The Commission finds necessary a clarification by what is meant by "blind". By "blindn the Commission means that the equal-percent method is ignorant of impacts. That is, if the revenue requiremenc was nor a constraint, certain classes would not receive an equal-percent increase due to price-elasticity reasons. The final prices would not equal those that result out of this docket for efficiency reasons. Of course, the same criticism holds for MCC's own proposal to just reconcile Bulk-Power costs. Moreover, the Commission's position that the equal-percent proposal is ignorant or blind to impacts is not new. Dr. Thomas Power has referred to the equal-percent reconciliation as the "rule of ignorance" in previous dockets before this Commission (e.g., see Order No. 4714d, Finding of Fact 17).

94. The Commission finds MCC's assertion, that MDU will "... earn revenues in excess of its costs of service and would in fact encourage the type of abuse of monopoly power that regulation was designed to prevent" as a result of an equal-percent reconciliation, to be a serious claim. The assertion appears to stem from the assumption that certain classes will receive an under-allocation (over-allocation) of costs combined, apparently, with a failure to recognize elasticity impacts, which, in this case, would assumably be stimulation (repression).

95. MCC's assertion that MDU will earn excess revenues, and the associated claim of encouraging monopoly power, is serioust The claim would appear to equally and generically apply to all of the above noted dockets in which equal-percent reconciliations have been adopted. This assertion also appears to raise the need to open a generic docket to investigate elasticity-based revenue adjustments and the sources of abusive monopoly power. Given the sweeping impact (see the next finding) of the assertion, all regulated utilities should probably be involved.

96. As a final comment on the MCC's assertion, that the "equal-percent" reconciliation results in the Company earning excess revenues with the result of encouraging the abuse of monopoly power that regulation was designed to prevent, the Commission would note the following. The Commission's concern is for the implications of the MCC's assertion as equally applied to other regulated markets. First, if it were applied to the te7ephone arena, the MCC's reconciliation proposal would appear to argue to pass through a majority of any revenue increase to toll) prices. It is not at all clear that this would be good public policy.

97. Second, in the gas arena the MCC's proposal would ap pear to suggest gas prices be raised relative to Basic Rates. With MDU, this would likely drive any remaining industrial load off the system. Third, if MCC's proposal that Bulk-Power energy costs need to increase to reflect energy costs in retail rate cases is logical (see MCC-2, page 45, lines 5-17), then the same argument would seem to apply to avoided cost prices, which would in turn have to be raised. A final concern, actually more of a question, involves how MCC's alleged "abuse of monopoly power" relates to the standard definition of cross subsidization and predatory pricing. This final concern/question will have to await an investigation.

98. Marginal Energy Costs: In its final COS motion, the MCC requests the Commission to either require MDU to use the energy values as "supported by the MCC and updated to 1988n, or require MDU to file backup material supporting the changed val ues in the Company's March 19, 1987, compliance filing. There are several dimensions to this motion each of which needs to be discussed.

99. First, while MCC supports the original data updated to 1988 dollars, it is not at all clear how MDU is to comply with using four or five years of data in the calculation, if 1988 dollars are used without rerunning the EGC model. That is, the original forecast-values are a constraint to using five years of data that the MCC approves of: Only three years of values (1988-1990) remain after moving to January 1, 1988 dollars if the EGC model is not rerun.

100. Two solutions, given the binding constraint, include: 1) only using three years of data or 2) escalating the last year's value at the 4 percent rate of inflation assumption used by MDU and

implicitly approved by MCC. A third solution involves rerunning the EGC model with 1988 as a base year which, assumably, the MCC would object to without an opportunity for discovery.

101. If instead of using MDU's original cost data, MDU's updated compliance filing data is used, then the practical problem of deferring action on any COS changes until the MCC has had a discovery opportunity emerges. However, since MCC has already stated it had "no fundamental disagreement" with MDU's inputs, functional form and outputs used in the EGC model to develop marginal energy costs, a comparison of the inputs would appear to be MCC's only remaining concern with the updated forecast.

102. Second, and before stating its decision, the Commission finds necessary a comment on MCC's motion that weaves together the revenue requirements and cost of service aspects of a rate case. Once more, the Commission would emphasize the lack of overlap in the revenue requirements, and cost of service and rate design objectives: A Commission approved level of coal prices for a 1985 test year is not at all necessarily related to forecast marginal fuel costs that begin in 1988 and run through 1991. COS and rate design do not use 1985 fuel prices as a proxy for, in this case, 1988 and beyond fuel costs.

103. The Commission's decision is to adopt MCC's motion to use the initial data from MDU's filing and not the updated data from assumably a 1987 rerun of the EGC model. As a result, cnly three years of data will be available beginning with 1988.

104. A final Commission comment is unrelated to any MCC motion for reconsideration and involves MDU's March 19, 1987, compliance filing provided all parties in this docket. A technical error has been detected by the Commission staff in MDU's workpapers involving the annualization of energy costs. MDU appears to have used an exponent in the annualization process that is inconsistent with the number of years of data involved. The result is to underestimate marginal energy costs by about 3 mills/kwh. MDU's compliance filing in response to this order must use consistent exponents with the years of data involved in marginal energy cost calculations. The MCC should realize that the resulting increase in energy costs, due to the correction, will significantly impact the class revenue requirements as developed in response to this order relative to the March 27 compliance filing.

RATE DESIGN MOTIONS

105. Introduction: MDU and the MCC filed three rate design motions for reconsideration. MCC's involves residential rate design. MDU's involves optional time-of-day and optional dual-fuel tariffs. Because the combined impacts of lowering the revenue requirement with the cost of service changes in this docket, rate design would have to be revisited regardless of the specific motions filed and discussed below.

106. Residential Rate Design: MCC moved for the Commission to lower the Base Rate from $4.50 to $3.00 per month, and make up any change in class revenue responsibility by, assumably, changing the commodity price (c/kwh). The MCC holds that its alternative rate will not result in uneconomic incentives for customers to consume electricity.

107. In summary, the Commission finds merit in MCC's motion to lower the Base Rate to $3.00. However, it should be noted that the Commission's decision, in this regard, stems largely from the reduced revenue requirement for the residential class. That is, the Commission's decision to lower the Base Rate also involves a concern that the commodity price does not move in the wrong direction. For an estimate of the impact of the combination of a lowered revenue requirement and a $3.00 Base Rate the next section of this order on final rate design decisions should be read.

108. The reason for this broader perspective is that the MCC's testimony raised a concern for the inefficiency that arises from setting prices on a basis other than cost. Then in its motion, the MCC states no "uneconomic incentive" will result from assumably adjusting the commodity price to reflect the reduction in the Base Rate. The Commission's point, which is reviewed in detail in the following findings, is that given the commodity price exceeds the relevant marginal costs supplied by the MCC, there is clearly an "uneconomic incentive" as a result of lowering the Base Rate instead of the commodity price towards the relevant marginal cost.

109. To illustrate this point, a comparison of three different values is required. The first value is cost. In this docket, MDU stated it could price down to as low as 6.212c/kwh and still recover all relevant short and long-run marginal costs (see Late Filed Exhibit No. 1, dated November

26, 1986) on Residential Rate 10. MCC even went lower, down to 3.267c/kwh (Late Filed Exhibit No. 1, dated January 12, 1987).

110. The second value is price and its importance is its relation to cost. By proposing to lower the Base Rate to $3.00 from $4.50, the commodity price does not move in the direction of the MCC's 3.267c/kwh marginal cost figure by as much as it would if a $4.50 Base Rate were retained. The third value is "willingness to pay", which brings the Commission to a reiteration of the logical corollary of MCC's pricing philosophy in this docket:

> The public interest is not served by a pricing policy that discourages additional electric sales from which the benefit derived is greater than the cost incurred in the provision of such additional sales (Order No. 5219b, Finding of Fact No. 342).

111. That is, an apparent inconsistency exists between the MCC's pricing philosophy, as stated in this reiteration, and MCC's statement in its motion that no "uneconomic incentive" results from lowering the Base Rate. Only if consumers have no willingness to pay for additional electricity between the floor cost (MCC's 3.267 cited above) and MCC's proposed price, are MCC's two positions consistent. In turn, one has to ask what implicit assumption is required for MCC's two positions to be consistent. The logical answer is that the elasticity of demand is zero. While precise elasticity of demand estimates are the topic of much debate, there is little debate on whether the value is zero or positive (in absolute value) in either the short or long run. It is only zero instantaneously. In this docket MDU provided its, unrebutted, elasticity of demand for the residential class which equalled .4057 in absolute value [see MDU Response to PSC Staff No.6 and Second Drzemiecki No.'s 15 and 17). This is a long-run estimate as are the costs used by the MCC in this docket.

112. The Commission's final decision on residential rate design is to the lower the Base Rate from $4.50 to $3.00. More importantly, the commodity price, the product for which the elasticity of demand is relatively greatest, will move in the direction of cost. The final rate design section of this order provides the Commission's estimates of the resulting commodity price.

113. Optional Time-Of-Day Rates: MDU's motion for reconsideration requests a complete withdrawal of the optional TOD Rates 16, 26 and 31. If residential Rates 10 and 16 are used as

examples, and if "load management" is one's objective, then MDU argues the annual flat rate on Rate 10 should be straddled by the marginal cost on- and off-peak prices on Rate 16, which is not the case when the Rate 10 annual flat rate equals around 7.5c/kwh. MDU's principal concern with the Commission's direction in Order No. 5219b appears to be that the Residential class' revenue requirement would not be recovered.

114. The Commission has two points to make before providing its decision on this motion. First, there arises a conflict in MDU's testimony on achieving, on one hand, its "load management" objective and, on the other hand, its subscription to Bonbright's ~optimum-use or consumer-rationing objective". The former objective appears to ignore the latter's concern which provides that rates should be designed to discourage the wasteful use of utility service while promoting all economically justified uses (Order No. 5219b).

115. It now appears clear to the Commission that MDU's key objective for proposing such an uneconomically high on-peak price on Rate 16 is to discourage on-peak consumption. If, however, MDU's load management objective is to flatten the annual load curve, one could devise a more effective pricing scheme than MDU proposed. That is, if load management is truly MDU's objective, as stated in its motion and reflected in its Rate 16 proposal, then why not really raise the on-peak price and, if necessary, pay consumers to consume power off-peak? Surely some such scheme would flatten the annual load curve.

116. One reason for not pursuing one of these load management schemes is the above cited "consumer-rationing" pricing objective. What if a customer is willing to pay a price that covers the actual on peak costs because the benefits received exceed the price paid? MDU's proposal for Rate 16, and the underlying "load management" objective, precludes such benefits from flowing to consumers and does not maximize welfare if willingness to pay is greater than cost but less than MDU's preferred price for achieving load management objectives.

117. MDU's concern for recovering the revenue requirement is also of interest. Whenever optional cost-based rates are designed and consumers respond to the optional rate, assumably it is to increase the amount of their income they can spend on other goods and services. That is, there likely was a subsidy flowing between customers on the otherwise mandatory rate. Anytime this is

the case, and a customer moves to the optional rate, a revenue shortfall would appear to arise. As a result, one gets into an iterative cycle of chasing, so to speak, an unrecovered revenue requirement.

118. This revenue requirement problem is not new to the Commission. When Mountain Bell (MB) proposed Local Measured Service (LMS) the same problem arose. This did not stop MB from proposing the LMS option, however.

119. It should also be noted that simply setting the onand off-peak prices on Rate 16 so that they "straddle" the annual flat rate on Rate 10, using the Residential class as an example, does not mitigate the revenue problem MDU raised. There are many sets of time-of-day prices that could "straddle" the flat rate on Rate 10. However, the historic optional time of day Rate 16 prices have been ineffective in attracting any meaningful consumer response. As a result, Rate 16 would not appear to have achieved MDU's load management objective. Also a result, no revenue problem assumably arises for MDU with its proposed optional time of day prices.

120. The choices before the Commission include: 1) MDU or MCC's proposed Rate 16 with its consequent welfare loss, 2) some other combination of Rate 16 prices that move prices in the direction of costs, but which may create a consumer response with the attendant revenue requirement and customer impact problems MDU has noted, 3) eliminating MDU's three optional TOD rates and 4) grandfathering optional TOD offerings.

121. The Commission's decision is to "freeze" (grandfather) the offering of optional time-of-day rates to existing subscribers. At present, the Commission understands MDU has several general service customers on optional time of day tariffs. Freezing the offerings- will minimize any unexpected rate shock for any existing subscribers to MDU's optional time-of-day rates. MDU is directed continue to file the existing three optional time-of-day tariffs, but to not offer the tariffs to any additional customers. Until further direction in a later docket is provided, the prices on the optional time-of-day tariffs should be based on the Company's proposal in this docket. In the future the prices on each tariff should change by the same percent change in revenue requirement for the otherwise applicable rate e.g., Rate 10 for Rate 16.

122. Dual Fuel Rates: The following reviews, in turn, the Commission's initial findings, the basis of MDU's motion, and the Commission's concerns and decisions on dual fuel rates.

123. The Commission's decision reflected MCC's concern that the "proposed rates for customers with energy charges fifty percent lower than the comparable firm service rates do not seem justified given the somewhat lower marginal cost of capacity" (Order No. 5219b).

124. In its motion, MDU requests the Commission to reconsider its decision on how dual fuel prices should be computed. MDU states the resulting dual fuel prices exceed the otherwise applicable prices due to a "double counting" of certain customer and transmission costs and the "low value attributed to the marginal cost of capacity."

125. As background, a number of points should be reviewed. First, it should be noted that MDU requested a stay of implementation of the dual fuel prices pending the outcome of its petition for reconsideration (from Mr. John Alke, received March 30, 1987). The Commission granted MDU's request (see Commission staff correspondence to Mr. C. Wayne Fox, dated March 31, 1987).

126. Second, it should also be noted that the dual fuel rates are optional interruptible rates, but only interrupted under certain conditions (based on time and temperature sensitive criteria). The quality of service is not the same as that on the otherwise applicable tariff(s). As a result the price signal should, other things being equal, be lower than that on the otherwise applicable tariffs.

127. Third, as evident from MDU's March 27 compliance filing, the Company appears to have misunderstood Order No 5219b on the number of dual fuel rates that should be tariffed: The Commission's order only referred to two tariffs (Rates 11 and 22) while MDU's filing includes three (Rates 11, 22 and 33). Then, MDU's motion only refers to rates 53 and 54 (new Rates 11 and 22). By its motion, MDU now appears to have withdrawn its proposed Rate 33.

128. With the above background, the Commission, upon revisiting the issue of optimal optional dual fuel rates, finds that its analysis in Order No. 5219b only partially reflects the concerns it now has with these tariffs. Two additional concerns not reflected in the Commission's Order No. 5219b, or for that matter other parties' analyses, follow.

129. One concern involves the temperature aspect of interruptions. On reconsideration, it is not at all clear that MDU's proposed criteria, that the temperature must be below zero degrees Fahrenheit, results in the avoidance of transmission and generation capacity costs. That is, MDU could end up making capacity purchases/additions because of peak loads occurring between the

hours of 5:00 P.M. and 9:00 P.M. when the temperature is above zero Fahrenheit. As a result, dual fuel customers would not be interrupted, but would get a price break, and MDU would still make additional capacity purchases: dual fuel customers would not allow for the avoidance of any costs.

130. A second concern derives from MDU's response to the Commission's information request in Order No. 5219b (Finding of Fact No. 351). The Commission's information request and MDU's response follow:

> Request: Demonstrate that the inability of the "superpeak" period to capture the peak load in all <u>summer months</u> is immaterial and/or incorrect when one turns to forecast data.
>
> Response: The inability of the "super-peak" period to capture the peak load in all <u>summer months</u> is immaterial because the magnitude of the peak load <u>in those months</u> is not comparable to the total forecasted peak. That is, the historical months where the "super-peak" period did not capture the peak load were not indicative of true peak load periods because of factors such as weather which dampened the peak load. The forecasted peak loads are indicative of normal peak occurrences in which the "super-peak" periods capture the peak load in all <u>summer months</u>. (emphasis added, see MDU Information Response dated March 26, 1987 from Mr. C. Wayne Fox.)

131. One must question the relevance of "summer months" in the above information response. As was discussed in detail in the Commission's final order, the Commission holds an error exists in MDU's and MCC's cost of service analyses regarding seasonality of costs (see Order No. 5219b, especially Finding of Fact Nos. 283-291 and 308-312). Neither party reflected the Company's own forecasts of summer-only system capacity peaks and the need to correspondingly purchase MAPP Schedule B and/or H capacity only in the summer.

132. The concern the Commission has, is given the system is expected to experience summer peaks and, in turn, it is in the summer when costs would be avoided, why have a cold-weather driven dual fuel rate? What are the chances MDU will experience a temperature below zero

degrees Fahrenheit between the hours 5:00 P.M. and 9:00 P.M. in the summer months? The projected avoidable incremental system costs do not jibe with MDU's dual fuel rate design.

133. As a result of the above concerns, the Commission not only grants MDU's request for a stay of implementing the proposed dual fuel tariffs, but requires MDU to freeze (grandfather) the offering of the dual fuel tariffs to its existing customers. The Commission will gladly consider alternative dual fuel tariffs in the future, but only after MDU reconciles the Commission's concerns with the Company's cost of service study. MDU must realize the need to have its tariffs reflect the dynamic balance of loads and resources and related change in avoidable costs.

134. With the freezing of the dual fuel tariffs certain further direction on pricing is necessary. First, the average percent change in the revenue requirement for the otherwise applicable rate(s), must be the basis of changes in prices on the dual fuel rates. For example, the pre-interim prices on Rate 54 should be changed by the average change in revenue requirements on Rates 20 and 30. These relations must be retained until customers no longer take service on the dual fuel rates, at which time the tariffs must be withdrawn. If, in the future, MDU files more accurate dual fuel tariffs, MDU must make explicit on the tariff that the price relationships may change overtime due to changed loadtresource balance conditions. With regard to the two grandfathered dual fuel tariffs, the Commission requests MDU to provide an interpretation and/or definition of "heating season" as appears on the two tariffs.

FINAL
COST OF SERVICE AND RATE DESIGN DECISIONS

135. Introduction: The remaining portion of this order contains two separate sections. The first section will explain how the revenue requirements of each class have changed. The second section provides changes in Commission policy needed to implement the intent of Order 5219b.

FINAL COST OF SERVICE

136. As noted earlier in this order, regardless of the specific cost of service and rate design motions for reconsideration received from MDU and the MCC, the Commission would have to

revisit the prices set for each class due to two general reasons. First, because the total increase in the revised Company revenue requirement, of about $235,859, is substantially lower than that in Order No. 5219b of about 1.8 million dollars. Second, due to the error in the Company's levelization of marginal energy costs, there occurs a change in each class' reconciled marginal cost revenue requirement.

137. In Table 1 below the Commission has compared the moderated revenue requirements and percent change in revenue requirements that resulted from each of Order No. 5219b and this order It is because of these revenue requirement changes, that earlier Order No. 5219b rate designs must be revisited.

Table 1

A Comparison of <u>Changed</u> Revenue Requirements From
Order Nos. 5219b and 5219c

	Order No. 5219b		Order No. 5219c	
Class/Rate	Revenue	Percent	Revenue	Percent
Residential/10	$525,972	4.7	-$303,184	-2.7
Small GS/20	626,708	12.3	301,942	5.9
Irrigation/25	14,268	13.0	14,268	13.0
Feed Grind/27	771	13.0	355	6.0
Large GS/30	28,816	.5	-164,671	-3.0
Industrial TOD/32	519,017	6.1	350,566	4.1
Lighting (Muni.)/42	8,245	13.0	8,245	13.0
Pumping (Muni.)/48	35,920	13.0	35,920	13.0
Private Light/52	32,557	13.0	8,182	3.3

Source: Derived from MDU=s March 19 and June 5, 1987, filings of Exhibit No. 1, page 3 of 3. Not all classes are reviewed above.

<u>FINAL RATE DESIGN</u>

138. Introduction: In the following, the Commission will review its earlier Order No. 5219b rate design decisions and make, as necessary, changes to address the aboye reviewed changes in revenue requirements. The absence of rate design decisions for a specific tariff means the Commission direction in Order No. 5219b remains unchanged with the exception, of course, of the above findings on motions for reconsideration.

139. Residential: Based on changes in the residential class' revenue requirement combined with the efficiency concerns both MDU and MCC argued in this docket, the Commission finds merit in a lowered commodity price. The MCC's $3.00 Base Rate is approved. Given the $3.00 Base Rate and the $10,812,488 revenue requirement, the commodity price will approximately equal 7.089c/kwh. This lowered commodity price is a move in the right direction, for an annual average rate, based on cost evidence submitted by MDU and the MCC.

140. Small General Electric: The Commission's Order No. 5219b direction with regard to this class' rate design, was later modified as discussed in correspondence to MDU (see Commission Staff correspondence dated March 31, 1987, to Mr. Fox). The final rate design is as stated in the following table.

Table 2
Small General Electric
Rate Design (Rate 20)

			Primary	Secondary
1)	Base Rate $12.70			
2)	Demand: ($/kw/mo)			
		> 10 kw	6.85	7.15
3)	Energy: (c/kwh)			
		< 2000 kwh	4.915	5.174
		> 2000 kwh	4.379	4.609

Source: Current tariff.

141. Due to the lowered overall final increase in the MDU's revenue requirement, this class received a roughly $324,766 reduction to the revenue requirement on which the above

prices are based. If the entire reduction were spread equally to each and every kwh, the reduction in the energy charges would equal about 0.3829c/kwh. If the $324,766 were flowed through to just the Base Rates, the $12.70 Base Rate would fall to about $6.40/month, or roughly a $6.30/month decrease. Other means by which to reflect the lowered revenue requirement could be developed.

142. The Commission's decision, based on concerns for rate moderation and efficient pricing, is to split evenly the reduction of $324,766, and flow through each half to the Base Rate and the energy charges. Based on cost/price comparisons, the decrease could arguably be flowed through to just the energy prices.

143. Mandatory Time-Of-Day Industrial: The reduced revenue requirement for this class of about $168,451 must be reflected by a uniform percent decrease to the demand charges and base rate.

CONCLUSIONS OF LAW

1. The Applicant, Montana-Dakota Utilities Company, furnishes electric service to consumers in Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

2. The Commission properly exercises jurisdiction over the Applicant's rates and operations. Section 69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

3. The Commission has provided adequate public notice of all proceedings and opportunity to be heard to all interested parties in this Docket. Title 2, Chapter 4, MCA.

4. The rate level and rate structure approved herein are just, reasonable, and not unjustly discriminatory. Section 69-3-330, MCA.

ORDER

1. The Montana-Dakota Utilities Company shall file rate schedules which reflect the Findings of Fact in this Order. These rate schedules shall reflect a revenue increase of $235,859, which is in lieu of, rather than in addition to, all increases previously granted in this Docket. The

total annual electric revenues of Montana-Dakota Utilities Company will be approximately $32,156,803.

2. All motions and objections not ruled upon are denied.

3. In submitting tariffs complying with this Order, MDU shall also submit work papers detailing billing determinants, final rates, and revenues generated for the existing and resulting rate design of each class.

4. Montana-Dakota Utilities Company shall provide the Montana Consumer Counsel's witness Mr. James Drzemiecki copies of all resulting tariffs and work papers also provided to the Commission staff.

5. This Order is effective for electric service rendered on and after June 18, 1987.

DONE AND DATED this 18th day of June, 1987, by a 3-0 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

HOWARD L. ELLIS, Commissioner

JOHN DRISCOLL, Commissioner

DANNY OBERG, Commissioner

ATTEST:

Ann Purcell
Commission Secretary

(SEAL)